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EXAMINER	
CRAIG, DWIN M	
ART UNIT	PAPER NUMBER
2123	

NOTIFICATION DATE	DELIVERY MODE
06/15/2010	ELECTRONIC

Please find below and/or attached an Office communication concerning this application or proceeding.

The time period for reply, if any, is set in the attached communication.

Notice of the Office communication was sent electronically on above-indicated "Notification Date" to the following e-mail address(es):

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Office Action Summary	Application No. 10/708,032	Applicant(s) WILLIAMS ET AL.	
	Examiner DWIN M. CRAIG	Art Unit 2123	

-- The MAILING DATE of this communication appears on the cover sheet with the correspondence address --

Period for Reply

A SHORTENED STATUTORY PERIOD FOR REPLY IS SET TO EXPIRE 3 MONTH(S) OR THIRTY (30) DAYS, WHICHEVER IS LONGER, FROM THE MAILING DATE OF THIS COMMUNICATION.

- Extensions of time may be available under the provisions of 37 CFR 1.136(a). In no event, however, may a reply be timely filed after SIX (6) MONTHS from the mailing date of this communication.
- If NO period for reply is specified above, the maximum statutory period will apply and will expire SIX (6) MONTHS from the mailing date of this communication.
- Failure to reply within the set or extended period for reply will, by statute, cause the application to become ABANDONED (35 U.S.C. § 133). Any reply received by the Office later than three months after the mailing date of this communication, even if timely filed, may reduce any earned patent term adjustment. See 37 CFR 1.704(b).

Status

1)☒ Responsive to communication(s) filed on *09 April 2010*.

2a)☒ This action is **FINAL**. 2b)☐ This action is non-final.

3)☐ Since this application is in condition for allowance except for formal matters, prosecution as to the merits is closed in accordance with the practice under *Ex parte Quayle*, 1935 C.D. 11, 453 O.G. 213.

Disposition of Claims

4)☒ Claim(s) *1-18* is/are pending in the application.

4a) Of the above claim(s) _____ is/are withdrawn from consideration.

5)☐ Claim(s) _____ is/are allowed.

6)☒ Claim(s) *1-18* is/are rejected.

7)☐ Claim(s) _____ is/are objected to.

8)☐ Claim(s) _____ are subject to restriction and/or election requirement.

Application Papers

9)☐ The specification is objected to by the Examiner.

10)☐ The drawing(s) filed on _____ is/are: a)☐ accepted or b)☐ objected to by the Examiner.

Applicant may not request that any objection to the drawing(s) be held in abeyance. See 37 CFR 1.85(a).

Replacement drawing sheet(s) including the correction is required if the drawing(s) is objected to. See 37 CFR 1.121(d).

11)☐ The oath or declaration is objected to by the Examiner. Note the attached Office Action or form PTO-152.

Priority under 35 U.S.C. § 119

12)☐ Acknowledgment is made of a claim for foreign priority under 35 U.S.C. § 119(a)-(d) or (f).

a)☐ All b)☐ Some * c)☐ None of:

1.☐ Certified copies of the priority documents have been received.

2.☐ Certified copies of the priority documents have been received in Application No. _____.

3.☐ Copies of the certified copies of the priority documents have been received in this National Stage application from the International Bureau (PCT Rule 17.2(a)).

* See the attached detailed Office action for a list of the certified copies not received.

Attachment(s)

1) ☐ Notice of References Cited (PTO-892)

2) ☐ Notice of Draftsperson's Patent Drawing Review (PTO-948)

3) ☐ Information Disclosure Statement(s) (PTO/SB/08) Paper No(s)/Mail Date _____.

4) ☐ Interview Summary (PTO-413) Paper No(s)/Mail Date. _____.

5) ☐ Notice of Informal Patent Application

6) ☐ Other: _____.

DETAILED ACTION

1. Claims 1-18 have been presented for reconsideration based on Applicants' amended claim language and arguments.

Response to Arguments

2. Applicants' arguments presented in the April 9th 2010 responses have been fully considered; the Examiner's response is as follows:

2.1 As regards Applicants' response to the objection to the specification because the Abstract was to long. The Examiner thanks the Applicants' for providing an amended Abstract and hereby withdraws the objection to the same.

2.2 As regards Applicants' response to the 35 U.S.C. 103(a) rejections of claims 1-13, Applicants' on page 9 of the April 9th 2010 responses argued;

"In order to establish a prima facie case of obviousness based upon a combination of references, there must be some reason provided by the Examiner to modify and combine the reference teachings in order to arrive at the claimed invention; and there must be a reasonable expectation of success in doing so.

The pump data model is a modeling or simulation program and can not be interpreted as data taken from sensors. The modeling or simulation program represents a database of models of fractures which will induce a pump data model depending of the data taken by the sensors which will fit the best representation of the well fracture."

The Examiner respectfully traverses Applicants' argument. Applicants' have *opined* that the claimed pump model cannot be based on data taken from sensors. The Examiner respectfully disagrees, an *empirical model* is a type of model that is derived from taking experimental data

and in the instant case the *empirical data* is used to model the manner in which the pump will perform over time, in this case a pump used for a *fracture treatment*. Note in Applicants' own specification in Figures 4 & 5 items 22a and 22b "Frac Fluid" which is known in the art as a *fracture treatment*. Therefore the modeled pump schedule as disclosed in *Brady et al.* is right on point and expressly teaches a model of a pump used in the *fracture treatment* as expressly disclosed in Applicants' specification and claims. Further *Brady et al.* teaches on page 7 that the net present value of the well pumping is calculated using *simulators* thus *Brady et al.* either explicitly or inherently teaches the use of a computerized model and/or simulator.

Thus, Applicants' arguments have been found to be unpersuasive and the previously Applied prior art rejections will be maintained.

2.3 As regards Applicants' response to the 35 U.S.C. 103(a) rejections of claims 14-18 the Examiner maintains the previously applied rejections for the reasons as set forth above.

Claim Rejections - 35 USC § 103

The following is a quotation of 35 U.S.C. 103(a) which forms the basis for all obviousness rejections set forth in this Office action:

> (a) A patent may not be obtained though the invention is not identically disclosed or described as set forth in section 102 of this title, if the differences between the subject matter sought to be patented and the prior art are such that the subject matter as a whole would have been obvious at the time the invention was made to a person having ordinary skill in the art to which said subject matter pertains. Patentability shall not be negatived by the manner in which the invention was made.

The factual inquiries set forth in *Graham* v. *John Deere Co.*, 383 U.S. 1, 148 USPQ 459 (1966), that are applied for establishing a background for determining obviousness under 35 U.S.C. 103(a) are summarized as follows:

1. Determining the scope and contents of the prior art.

2. Ascertaining the differences between the prior art and the claims at issue.
3. Resolving the level of ordinary skill in the pertinent art.
4. Considering objective evidence present in the application indicating obviousness or nonobviousness.

This application currently names joint inventors. In considering patentability of the claims under 35 U.S.C. 103(a), the examiner presumes that the subject matter of the various claims was commonly owned at the time any inventions covered therein were made absent any evidence to the contrary. Applicant is advised of the obligation under 37 CFR 1.56 to point out the inventor and invention dates of each claim that was not commonly owned at the time a later invention was made in order for the examiner to consider the applicability of 35 U.S.C. 103(c) and potential 35 U.S.C. 102(e), (f) or (g) prior art under 35 U.S.C. 103(a).

3. Claims 1-13 are rejected under 35 U.S.C. 103(a) as being unpatentable over "Cracking Rock: Progress in Fracture Treatment Design" hereafter referred to as *Brady et al.* in view of U.S. Patent Publication US 2002/0198819 to Munoz et al.

3.1 As regards independent claims 1, 2, 8 and 10 and using claim 2 as an example; *Brady et al.* teaches; a method of determining a pumping schedule corresponding to a particular return on investment for a particular wellbore, the pumping schedule including an initial pumping schedule and a remaining pumping schedule, comprising the steps of:

(a) fracturing one or more perforations in a formation penetrated by the particular wellbore, thereby creating one or more fractures in said formation, in accordance with said initial pumping schedule;

See page(s) 5 and 6;

The method took off. By 1955, treatments reached 3000 wells per month, and by 1968, more than a half-million jobs had been performed. Today, hydraulic fracturing is used in 35 to 40% of wells, and in the United States, where the procedure is most widespread, it has increased oil reserves by 25 to 30%.[3] Interest in hydraulic fracturing shows no signs of abating.[4] Application of the technology is expanding from mainly

low-permeability reservoirs to medium-to high-permeability settings (*above*).

Hydraulic fracturing is the pumping of fluids at rates and pressures sufficient to break the rock, ideally forming a fracture with two wings of equal length on both sides of the borehole. If pumping were stopped after the fracture was created, the fluids would gradually leak off into the formation. Pressure inside the fracture would fall and the fracture would close, generating no additional conductivity. To preserve a fracture once it has been opened, either acid is used to etch

(b) analyzing a set of fracture characteristics associated with said one or more fractures in response to the fracturing step;

See page 7;

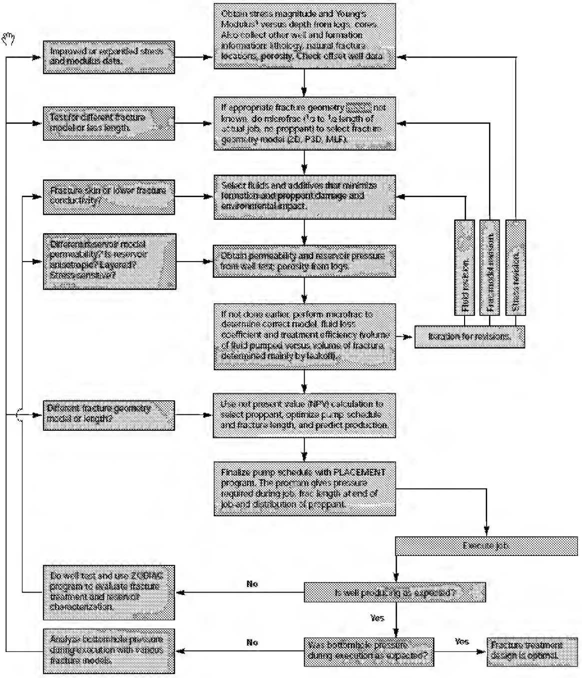
(c) interrogating a pump data model being a modeling or simulation program in accordance with said remaining pumping schedule;

See Page 8, more specifically;

- Fracture treatment evaluation. Mathematical advances have also made evaluation tools more powerful. There is a growing practice of testing the validity of the fracture geometry model against postfracture well test data, then refining the model. This "back analysis" permits prediction of fracture parameters, particularly fracture length and conductivity, to be compared with independent field measurements.

Claim interpretation, the claimed *interrogating a pump data model* is being interpreted to mean interpreting the data taken from sensors in a well-bore and then, based on those measurements changing a pumping schedule see the flow chart on page 15, presented above, further note the step of finalizing the pump schedule, which functionally performs that same process step as

Design of an Ideal Fracture Treatment



1. Young's Modulus is the ratio of stress (force per unit area) to strain (displacement per unit length).

interrogating the pump model. Note also that the inputs from the left side of the diagram show inputs from various sensors. Further it is noted that it would be obvious to an artisan of ordinary skill, at the time of the invention to have computerized the claimed method and to have a program executing that interrogates the pump model.

Further on page 7 is disclosed the teaching;

"Pivotal to designing the treatment - and to deciding whether to do one at all--is cost- benefit analysis, relating cost of the fracture job to increased well productivity, The more fracture length for a given fracture conductivity, the more productivity, but also the more costly the fracture job, This analysis, called net present value, is done ***with simulators*** that find the optimum fracture length and conductivity for a given payback schedule, Too short a fracture, or too low a conductivity, and the increase in well productivity won't cover the cost of the fracture treatment; too long, and the extra fracture length will add significantly to cost but negligibly to production, Some simulators model fracturing economics in longer terms; they tell, for example, for a well with a given deliverability, amortized at a certain rate, how much should be spent on hydraulic fracturing given a future oil price," It is inherent to *Brady et al.* that these *simulators* are computerized simulators.

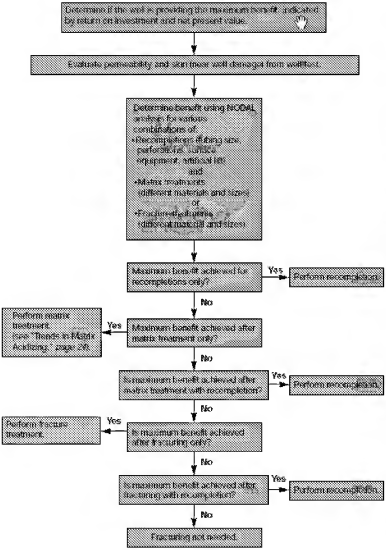
Also on page 14 is disclosed;

A typical problem is that posttreatment transient pressure analysis shows the fracture is shorter than indicated by the volume and leakoff of pumped fluid. There could be several reasons for the disparity. A common reason, however, is that most postfracture evaluation models assume ideal reservoir conditions—homogeneous and isotropic formations, uniform fracture width and conductivity and absence of skin damage.[24]

To get away from assuming ideal reservoir conditions, Schlumberger has made several improvements to the ZODIAC Zoned Dynamic Interpretation, Analysis and Computation program. This program improves evaluation by accounting for variation in fracture conductivity and width along the fracture length, for reservoir permeability anisotropy and for fracture face skin damage.[25] It also does not link fracture height with bed thickness (above), but uses a P3D approach to permit variation in propped fracture height and width in the analysis. Compared to conventional postfracture pressure transient analysis, the program takes 10 to 15% more computer time on a VAX or Sun workstation. In the future, it will include capabilities to model the effects of reservoir boundaries and high-velocity flow on fracture length and conductivity estimates. The effects of reservoir boundaries are often observed in transient tests of long duration. These effects can be used to estimate the area and shape of the drainage area of the well.

(d) determining a particular return on investment for said particular wellbore in response to the interrogating step, said pumping schedule corresponding to said particular return on investment for said particular wellbore being determined when said pump data model is interrogated in response to said remaining pumping schedule. See page 15, below;

To Frac or Not to Frac?



Fracture Geometry Modeling

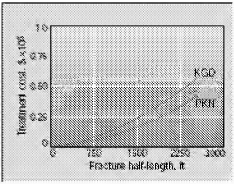
The need to understand hydraulic fracturing stimulated advances in basic rock mechanics. A key finding was of Hubbert and Willis, in 1957, showing that fractures in the earth are usually vertical, not horizontal.[7] They reasoned that because a fracture is a plane of parting in rock, the rock will open in the direction of least resistance. At the depth of most pay zones, overburden exerts the greatest stress, so the direction of least stress is therefore horizontal (*next page, top*). Fractures open perpendicular to this direction and are therefore vertical. In shallow wells, or where thrusting is active, horizontal stress may exceed vertical stress and horizontal fractures may form.

By the 1960s, fractures created below 1000 or 2000 ft [300 to 600 m] were accepted as vertical. Operators then posed some difficult questions: How high does the fracture grow? How can we prevent it from extending into the gas or water zone? How does fracture height relate to fracture width and length? And how do we optimize fracture dimensions?

A major task of rock mechanics became the prediction of fracture height, length and width for a given injection rate, duration of injection and fluid leakoff. Needed for this prediction is a model of how a fracture propagates in rock.

Today, a number of models occupy a continuum from 2D to pseudo-three-dimensional (P3D) and fully 3D. The basic difference between 2D and P3D/3D models is that in 2D models, fracture height is fixed or set equal to length (that is, a semicircular shape), whereas in P3D and 3D models, fracture height, length and width can all vary somewhat independently. Two-dimensional models have been around for about 30 years; three-dimensional for about ten years. Increased computing power has recently made pseudo-3D models practical for routine design. Fully 3D models have

Note the block with the words, *return of investment* and *net present value* further see page 13 the treatment cost of different frac fluid techniques, see also on page 7 the discussion of fracturing economics given a future oil price. The teaching of a future oil price would be a factor in determining a particular rate of return, also see the chart below from page 13;



However, *Brady et al.* does not expressly or specifically disclose, a particular return on investment.

Munoz et al. teaches a particular return on investment after calibrating a model, see Figure 7 for the modifying of a model teaching and Figure 1 for a teaching of a target Return on Investment, see also paragraph [0004] and [0061] specifically for calibration of a cost model.

Brady et al. and *Munoz et al.* are analogous art because they both come from the same problem solving area of calculating a return on investment.

At the time of the invention, it would have been obvious, to a person of ordinary skill in the art to have combined the ROI teachings of *Brady et al.* with the ROI teachings of *Munoz et al.*

The motivation for doing so would have been to increase oil reserves in existing wells by performing hydraulic fracturing and thus be able to recover more oil without the time and expense of having to drill a new well, see page 5 of *Brady et al.*

> The method took off. By 1955, treatments reached 3000 wells per month, and by 1968, more than a half-million jobs had been performed. Today, hydraulic fracturing is used in 35 to 40% of wells, and in the United States, where the procedure is most widespread, it has increased oil reserves by 25 to 30%.[3] Interest in hydraulic fracturing shows no signs of abating.[4] Application of the technology is expanding from mainly

Further an artisan of ordinary skill would be motivated to use the methods as disclosed in *Munoz et al.* in order to maximize the Rate of Return on Investment based on the risk level of a particular endeavor, see paragraph [0008] of *Munoz et al.*

Therefore it would have been obvious to combine the teachings of *Munoz et al.* with the teachings of *Brady et al.* in order to obtain the invention as specified in claims 1-13.

3.2 As regards claim 3, *Brady et al.* teaches analyzing a set of fracture characteristics , see page 10, more specifically the stress profile measure by microfrac and derived from wire-line log data and further teaches calibrating the pump data model, see page 10, note the discussion regarding calibration treatment when a fracture is created.

3.3 As regards claim 4, *Brady et al.* teaches interrogating model in response to the remaining pump schedule, see page 15 and the flow chart disclosed above.

3.4 As regards claim 5, *Brady et al.* teaches determining the return on investment after the pump model and the pump schedule have been optimized, see page 15 and the flow chart disclosed above.

3.5 As regards claim 6, *Brady et al.* teaches changing frac fluid and proppant, see page 8 as regards the use of frac fluid and see page 7 as regards the use of proppant.

3.6 As regards claim 7, *Brady et al.* see the rejection of claim 5 above.

3.7 As regards claim 9, *Brady et al.* see the rejection of claim 4 above.

3.8 As regards claim 11, *Brady et al.* teaches;

(a1) fracturing said formation penetrated by said wellbore in accordance with said initial pumping schedule, see the discussions from pages 9 & 12 regarding pump schedules,

(a2) generating a set of fracture characteristics in response to the fracturing step (a1); see the flow chart on page 15, specifically the step involving "Obtain stress magnitude and Young's Modulus versus depth from logs, cores. Also collect other well and formation information: lithology, natural fracture locations "

(a3) analyzing said set of fracture characteristics, see page 14 "analysis was performed on the first six development wells"

(a4) calibrating the pump data model in response to the step (a3) thereby generating a calibrated pump data model, See page 7 and the discussion at the bottom of column 1 which discuses, Fracture Treatment Evaluation and testing the validity of the fracture geometry model

which is functionally the same as calibrating the fracture geometry model which will is the same as calibrating the claimed pumping model.

3.9 As regards claim 12, *Brady et al.* see the rejection of claim 5.

3.10 As regards claim 13, *Brady et al.* teaches frac-fluid and proppant, see page 8 the flow chart which is entitled "To Frac or Not to Frac?" see also the discussion on page 6, specifically about fluid and the use of proppant.

4. Claims 14-18 are rejected under 35 U.S.C. 103(a) as being unpatentable over *Brady et al.* in view of *Munoz et al.* as applied to claims 10-13 above and in further view of U.S. Patent 5,934,373 to Warpinski et al.

4.1 *Brady et al.* as modified by *Munoz et al.* teaches calibrating a pump model after receiving fracture data from a wellbore as recited in claims 1-13 for the reasons above, differing from the invention as recited in claims 14-18 in that their combined teaching lacks

(Claim 14) interrogating the pump data model in response to the initial pumping schedule thereby generating a set of pump data model fracture characteristics, generating a set of tiltmeter data fracture characteristics on the condition that a tiltmeter data sensor is located adjacent the fractures, and generating a set of micro-seismic data fracture characteristics on the condition that a micro-seismic data sensor is located adjacent the fractures.

(claims 15) determining whether said set of pump data model fracture characteristics substantially matches said set of tilt- meter data fracture characteristics and said set of micro-seismic data fracture characteristics.

(claim 16) said set of pump data model fracture characteristics substantially matches said set of tiltmeter data fracture characteristics and said set of micro-seismic data fracture characteristics.

(claim 17) interrogating said calibrated pump data model in response to said remaining pumping schedule thereby generating a return on investment.

(claim 18) (b) for interrogating a pump data model comprises the step of:
(b l) changing a proportion of a frac fluid and a proppant in said remaining pumping schedule thereby generating a new remaining pumping schedule; and
(b2) interrogating said calibrated pump data model in response to said new remaining pumping schedule thereby generating a return on investment.

Warpinski et al. teaches the use of tiltmeter fracture data used to modify a model of a wellbore Figure 9 and Col. 8 lines 1-56 (claims 14-16) as regards claim 17 see the rejection of claim 11 above, as regards the rejection of claim 18 see the rejection of claim 13 above.

Brady et al., Munoz et al. and *Warpinski et al.* are analogous art because they all come from the same problem solving area of data modeling and training a model using real-world data.

Therefore it would have been obvious to one having ordinary skill in the art at the time of the invention was made to have utilized the tiltmeter fracture data in the fracture models as disclosed in *Brady et al.* in order to modify the data model to effect the pump schedule and determine the return on investment if the injection of frac fluid into a wellbore is to be performed. The motivation for doing so would have been to provide for a means to measure hydraulic fracture dimensions to provide useful data on the deformations of the rock caused by

the fractures, specifically how fractures are forming in wellbores, see Col. 2 lines 45-67 of *Warpinski et al.*

Conclusion

5. Applicant's amendment necessitated the new ground(s) of rejection presented in this Office action. Accordingly, **THIS ACTION IS MADE FINAL**. See MPEP § 706.07(a). Applicant is reminded of the extension of time policy as set forth in 37 CFR 1.136(a).

A shortened statutory period for reply to this final action is set to expire THREE MONTHS from the mailing date of this action. In the event a first reply is filed within TWO MONTHS of the mailing date of this final action and the advisory action is not mailed until after the end of the THREE-MONTH shortened statutory period, then the shortened statutory period will expire on the date the advisory action is mailed, and any extension fee pursuant to 37 CFR 1.136(a) will be calculated from the mailing date of the advisory action. In no event, however, will the statutory period for reply expire later than SIX MONTHS from the date of this final action.

5.1 Any inquiry concerning this communication or earlier communications from the examiner should be directed to DWIN M. CRAIG whose telephone number is (571)272-3710. The examiner can normally be reached on 10:00 - 6:00 M-F.

If attempts to reach the examiner by telephone are unsuccessful, the examiner's supervisor, Paul L. Rodriguez can be reached on (571) 272-3753. The fax phone number for the organization where this application or proceeding is assigned is 571-273-8300.

Information regarding the status of an application may be obtained from the Patent Application Information Retrieval (PAIR) system. Status information for published applications

may be obtained from either Private PAIR or Public PAIR. Status information for unpublished applications is available through Private PAIR only. For more information about the PAIR system, see http://pair-direct.uspto.gov. Should you have questions on access to the Private PAIR system, contact the Electronic Business Center (EBC) at 866-217-9197 (toll-free). If you would like assistance from a USPTO Customer Service Representative or access to the automated information system, call 800-786-9199 (IN USA OR CANADA) or 571-272-1000.

/Dwin M Craig/
Primary Examiner, Art Unit 2123